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THE ABB LEBS SYSTEM DESIGN

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ABSTRACT

The objectives of the U.S. Department of Energy (DOE) "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems" (LEBS) project are to dramatically improve environmental performance of future pulverized coal-fired power plants, to increase their efficiency and to reduce their cost of electricity using near-term technologies, *i.e.*, advanced technologies that are partially developed. The overall objective is to expedite commercialization of the technologies that are developed. The paper describes the work by the ABB team on the LEBS project which is part of the DOE's Combustion 2000 Program.

A major deliverable of the Project is the design of a 400 MWe commercial generating unit (CGU). The design being developed by the ABB team is projected to meet all the project objectives and to reduce emissions of NO_X, SO_2 and particulates to one-third to one-sixth NSPS limits while increasing net station efficiency significantly and reducing the cost of electricity. Development activities supporting the design work are described in the paper.

INTRODUCTION

The LEBS performance objectives and the technologies selected to attain the objectives are summarized in Table 1. [1]

TABLE 1 - ABB's LEBS Performance Objectives and Technologies

	Objective	Technology
Emissions, lb/Million Btu		
NO_X	0.1	TFS 2000™
SO_2*	0.1	Hot SNO_X™ or NID™
Particulates	0.01	Hot SNO_X™ or NID™
Efficiency (Net Plant, HHV)	42%	Advanced Rankine Cycle
	or 45%	Kalina Cycle

*3 lb SO_2/Million Btu in the coal

All of the technologies listed in Table 1 meet the project definition of "near-term". The development work leading to commercial readiness of these technologies is described below. The recent major activities have been: (1) in-furnace NO_X reduction, (2) catalytic filter optimization and (3) proof-of-concept test facility (POCTF) design/licensing with a Kalina cycle.

IN-FURNACE NO_X REDUCTION

Introduction. ABB's TFS 2000™ firing system was selected in Phase I of the LEBS project. It has been demonstrated to provide NO_X emissions of 0.2 pounds/MM Btu in prior laboratory and full scale, retrofit, utility boiler applications The objective of recent development work was to reduce this value to 0.1 lb/MM Btu while maintaining the fly ash carbon content <5% for high sulfur, mid-western and eastern bituminous coals. In addition, the lower furnace heat absorption profiles and convective pass

heat flux distribution were to remain similar to or improved over the existing system. Specific features of this system include the use of concentric firing system (CFS) air nozzles, where the main windbox secondary air jets are introduced at a larger firing circle than the fuel jets; close coupled overfire air (CCOFA) for improved carbon burnout; and multi-staged separated overfire air (SOFA) to provide for complete combustion while maintaining an optimum global stoichiometry history for NO_X control. In addition, the TFS 2000™ firing system includes flame attachment coal nozzle tips for rapid fuel ignition and a pulverizer configured with a DYNAMIC™ Classifier to produce fine coal to minimize carbon losses under these staged combustion conditions.

Potential enhancements to the TFS 2000™ firing system focused on optimizing the introduction of the air and fuel within the primary windbox zone to provide additional horizontal and vertical staging. These enhancements were based on controlling the combustion of the coal in a more local sub-stoichiometric environment. That is, in addition to the global staging currently applied, improved NO_X reduction was sought by controlling and optimizing the mixing of the fuel and air locally through vertical and horizontal staging techniques. The approach used in the development and evaluation of the various firing system concepts included an integrated approach of kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale combustion testing in a Boiler Simulation Facility (BSF). These techniques were applied to better understand the mechanisms governing in-furnace NO_X reduction and to identify potential enhancements to the TFS 2000™ firing system.

<u>Pilot Scale Combustion Testing.</u> The BSF is a pilot scale test furnace, nominally rated at 50 MM Btu/hour (5 MWe) for coal firing, that reliably duplicates the combustion characteristics of a tangentially-fired utility boiler. All major aspects of a typical tangentially-fired utility boiler are duplicated in the BSF including a v-shaped hopper for bottom ash collection, the use of multiple burner elevations, and an arch with subsequent backpass convective "superheat," "reheat," and "economizer" surfaces. Selective refractory lining over atmospheric pressure "waterwalls" allows the matching of the residence time/temperature history of large scale utility boilers, including the horizontal furnace outlet plane (HFOP) gas temperature. The BSF is fully instrumented to monitor the combustion process. Instruments for measuring coal feed rate, primary and individual secondary air mass flow rates, outlet emissions (O_2, CO_2, CO, SO_2, NO, and NO_X), and convective pass heat flux distribution are tied into a combined DCS/data acquisition system to allow for control and logging of these and other important operational parameters. The coal utilized was the high sulfur, medium volatile, bituminous Viking coal from Montgomery, Indiana.

Prior to the initiation of NO_X control subsystem testing, the firing system for the BSF was modified to take advantage of current and previous R&D project findings. First, ABB's Aerotip™ coal nozzle tip design was utilized as the base from which the BSF coal nozzles were constructed. The Aerotip™ design embodies improved aerodynamic features which support the test program need for a low NO_X coal nozzle tip through its control over near field stoichiometry. In addition, the main windboxes were designed to accommodate a range of vertical and horizontal air and coal staging scenarios. The design of the secondary air nozzles was based on the need to maintain proper jet momenta, while having sufficient flexibility to test variations in vertical and horizontal air staging. Excess coal nozzle capacity was incorporated to allow the testing of various coal staging scenarios, including two-corner coal firing. With this foundation, each of the "base" (*i.e.*, benchmark) firing system designs tested, including the TFS 2000™ firing system, was able to incorporate the results of the prior chemical kinetic modeling and small scale (FSBF) combustion testing with respect to main windbox vertical air staging.

Various "conventional" global air staging techniques were tested in order to benchmark their NO_X reduction potential on the test fuel. This work included investigations of close coupled overfire air (CCOFA), upper and lower (single) elevations of separated overfire air (SOFA), and an implementation of TFS 2000™ technology. All of the various overfire air configurations utilized the same main windbox arrangement, and all were performed with high fineness (90% - 200 mesh) coal grind. A summary of the results from testing various overfire air configurations are given in Figure 1. As anticipated, the implementation of global air staging results in a significant reduction in furnace outlet NO_X emissions. Beginning with NO_X emissions of 0.52 pounds/MM Btu with a typical "baseline" (post-NSPS) firing system arrangement, NO_X reductions continued to a low of 0.13 pounds/MM Btu for an "optimized" TFS 2000™ firing system arrangement (Note: similar 0.13 pounds/MM Btu outlet NO_X emissions were obtained with the upper SOFA only, but this was at slightly degraded carbon in the fly ash performance). The "optimized" TFS 2000™ system incorporates improvements to the bulk

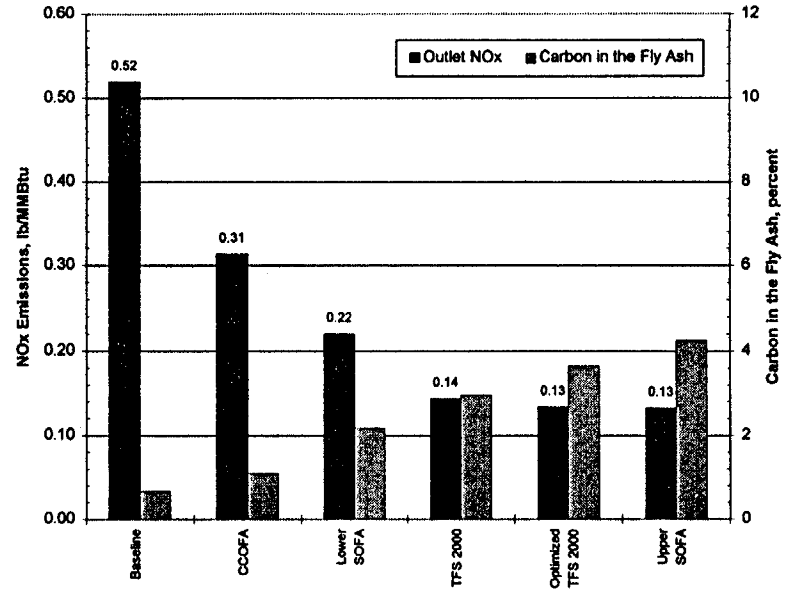

Figure 1 Global Staging

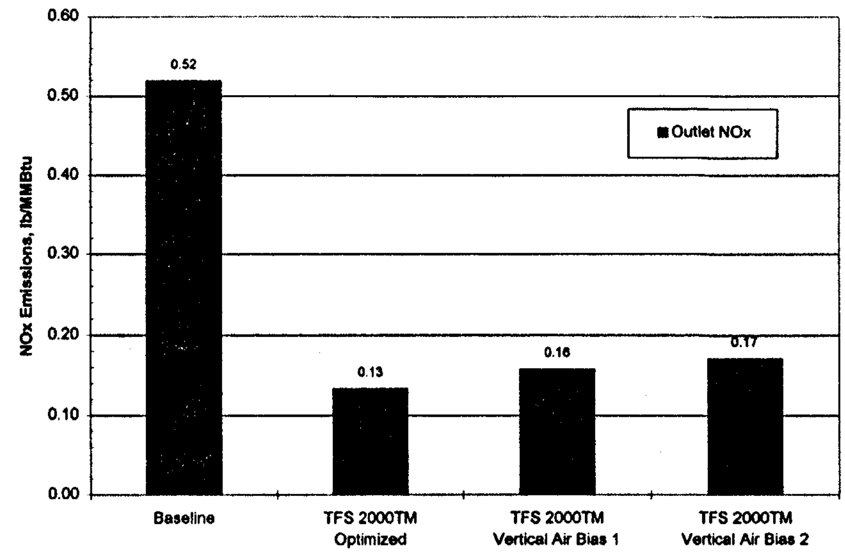

Figure 2 Effects of Vertical Staging on NOx

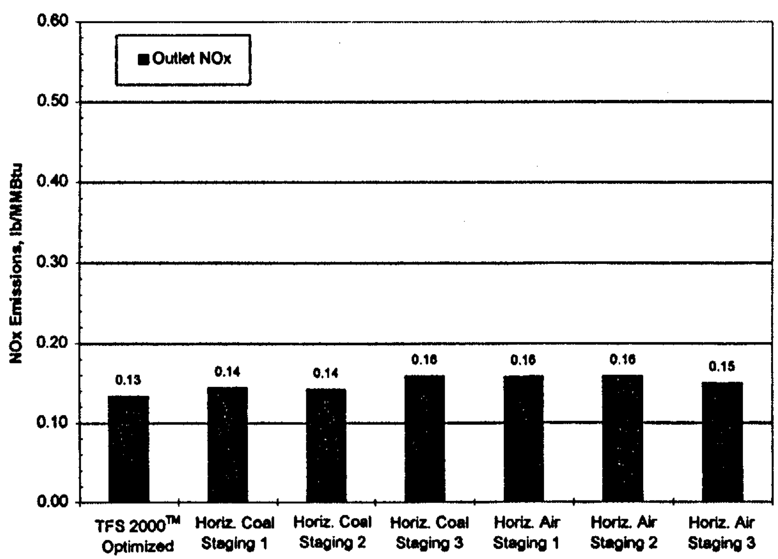

Figure 3 Effects of Horizontal Staging on NOx

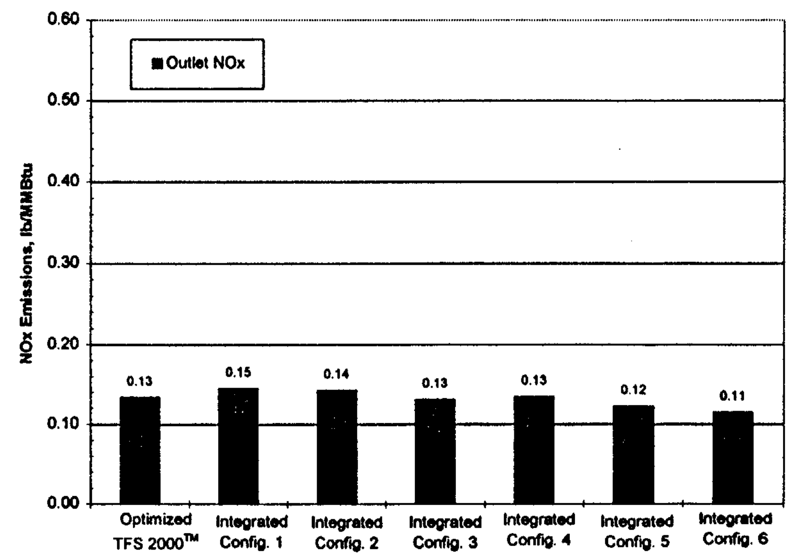

Figure 4 Effects of Integrated Staging on NOx

stoichiometry history. In all, a 75% reduction in NO_X from baseline levels was achieved with the "optimized" TFS 2000™ system. As expected, carbon in the fly ash increased as the global staging was increased, but remained below the limit of 5%.

Having benchmarked the effects of global staging on firing system performance, both vertical and horizontal staging techniques within the main firing zone were subsequently tested. The objectives of this work were to confirm the results of prior main windbox vertical air staging work, and to further reduce outlet NO_X emissions from the previously demonstrated "best" level of 0.13 pounds/MM Btu. As such, these methodologies were applied in concert with the "optimized" TFS 2000™ firing system, keeping the global stoichiometry history constant to allow meaningful comparisons.

First, vertical air staging within the main windbox was independently varied to demonstrate its effect on NO_X formation at this large pilot scale. Results from this testing, given in Figure 2, show that significant variation in NO_X emissions occur as main windbox vertical air staging is changed. This result confirms that the main windbox vertical stoichiometry history is an important contributor to overall NO_X formation, even with significant levels of global air staging. Overall, NO_X emissions increased when variations to the main windbox vertical stoichiometry build-up were applied to the previously "optimized" TFS 2000™ arrangement. This result is, however, expected since the "optimized" TFS 2000™ system incorporates the results of prior chemical kinetic modeling and small scale combustion test vertical air staging work into the configuration of its main windbox as noted above.

Next, horizontal staging, used to control the horizontal "build-up" of stoichiometry (corner to corner) within the main burner zone, was evaluated. This was accomplished by biasing the fuel and air between one or more of the four corners. Tested subsets of this technique are two corner firing, where all of the air and fuel are injected through two of four corners in a tangential arrangement, and opposed corner firing where the coal is injected from two corners, and the air from the remaining two. In general, independent implementation of horizontal staging techniques resulted in neutral to degraded NO_X emission performance over that of the "optimized" TFS 2000™ firing system. This is seen in Figure 3. These results demonstrate that, similar to the prior vertical staging experiments, outlet NO_X emissions can be affected by horizontal fuel and air distributions. However, these results also demonstrate that the global time - stoichiometry history (*i.e.*, the TFS 2000™ stoichiometry profile) dominates the NO_X formation and reduction processes at these levels of global air staging.

Finally, several configurations which applied integrated vertical and horizontal staging techniques as a means of "optimizing" the stoichiometry of combustion within the main windbox were evaluated. Integrated vertical and horizontally staged firing systems were extensively evaluated using CFD modeling prior to the BSF tests. In contrast to their independent performance, Figure 4 shows that when suitably combined, an integrated vertical and horizontal staging strategy offers a small, but consistent improvement to the NO_X emissions performance. At a NO_X emission level of 0.11 pounds/MM Btu, the "best" integrated system ("Integrated Config. 6") produced a greater than 10% reduction in NO_X over the previously "optimized" TFS 2000™ system. Carbon loss results (not shown) were similar for the two firing systems.

Additional pilot scale testing of potential NO_X control subsystems in the BSF has been recently completed and results are being analyzed. The objective of this testing was to confirm the performance of the integrated vertical and horizontal staging technique, focusing on the repeatability of the present test results, while generating design information for this and other promising firing system concepts for eventual full scale utility boiler application.

CATALYTIC FILTER OPTIMIZATION

Introduction. The principal goal of the Catalytic Filter Optimization activities is the acquisition of initial field test data, which will be used for a larger field demonstration. These activities include the determination of feasible and reasonable operating conditions for the catalytic filter system. Data collected through testing focused on particulate and NO_X removal efficiencies as well as filter draft loss.

The goals of this task are listed below in order of priority. It is desirable that these goals be achieved simultaneously.

- Particulate emissions of less than 0.005 lb/MM Btu

- Maximum filter clean-side draft loss of 8 inches w.g. at 4 ft/min at 775°F
- Operation with a Filter Face Velocity (FFV) of at least 4 ft/min at 650°F
- Minimum of 80 % NO_X removal efficiency
- Ammonia slip of less than 15 ppm

Information gained from demonstration and evaluation will address the following issues:

- Confirm filter particulate removal efficiency.
- Determine the tubesheet differential pressure (filter draft loss) as a function of face velocity, cleaning cycle characteristics, operating time, and other parameters.
- Determine the NO_X reduction efficiency as a function of flue gas composition (NO_X inlet concentration, NH_3 stoichiometry, particulate removal), and flue gas temperature. Of further interest is the determination of the requirements to maintain the catalytic conversion efficiency.

Approach. The approach used is to test the catalytic filter system with four filter modules on a 100 ACFM (165 m^3/hr) slipstream at Richmond Power & Light's Whitewater Valley Station Unit 2, a 66 MWe pulverized coal-fired boiler. CeraMem manufactured the ceramic filter modules and Engelhard applied the NO_X reduction catalyst. At this writing, an initial 500-hour test has been concluded, in which both particulate removal and NO_X reduction were investigated.

Preliminary Results. *The tubesheet differential pressure* (filter draft loss) is considered an essential element to the success of the catalytic filter. For the first 500-hour test, the initial tubesheet differential pressure was approximately 16 inches w.g. (FFV=4 ft/min, T= 650°F). The filter permeance, a parameter inversely proportional to tubesheet differential pressure and independent of filter face velocity and process temperature, decreased through the first 150 hours of operation, as shown in Figure 5. This decrease indicated that the filter tubesheet differential pressure increased at constant process conditions, an effect that is typical of all ceramic particulate filters. This decrease in permeance or increase in tubesheet differential pressure is caused by the smaller particulate (less than 0.5μ diameter) becoming permanently lodged in the filter substrate. For all ceramic particulate filters, the filter permeance should stabilize at some point, indicating that essentially the pores that are able to become "plugged" have been, and that the filter is being cleaned efficiently. At this point, the tubesheet differential pressure will remain constant at constant process conditions. In the case of the initial 500-hour test, the tubesheet differential pressure rose to approximately 23-24 inches w.g. (FFV=4, T=650°F) after approximately 200 hours of operation and was stable for the remainder of the test.

Upon conclusion of the 500-hour test, the system was opened and the filter modules were inspected. Visual inspection showed that the filters were being cleaned effectively, with no particulate buildup being detected and no plugged channels being found. Subsequent analysis of the catalytic filters indicate that catalyst addition was responsible for approximately 75 % of the tubesheet differential pressure.

Particulate removal for this filter system was expected to be near absolute. In previous laboratory testing outlet emissions from the filter could not be detected using a laser light-scattering measurement system, indicating that removal efficiency exceeded 99.99994%. In the 500-hour test, two outlet particulate samples were taken, with results indicating a removal efficiency of 99.93% which is below the expected value. Upon completion of the 500-hour test, the unit was opened and the tubesheet and vessel inspected. Lack of particulate matter on the "clean-side" of the tubesheet, particularly in cracks and crevices, tends to indicate that particulate matter was not passing through the filters and that the sampling results were reflective of material that had been left in the ducts when the system was being bypassed.

NO_X Reduction Efficiency testing was initiated after approximately 350 hours of operation. Ammonia was injected into the system to facilitate the NO_X reduction reaction. Inlet and outlet ammonia sampling was conducted to quantify ammonia injection rates and ammonia slip, while NO_X inlet and outlet concentrations were determined using two ThermoElectron Model 10 NO_X CEMs. Due to vendor problems that are beyond the scope of the paper, maximum injection stoichiometry was limited to 0.4 (maximum ammonia concentration in the inlet flue gas was approximately 200 ppm). Preliminary results indicate that the catalyst made efficient use of the ammonia, as shown in Figure 6. The ammonia was fully accounted for in the NO_X reduction reaction, and sampling and analysis found less than 3 ppm in the outlet flue gas in all samples.

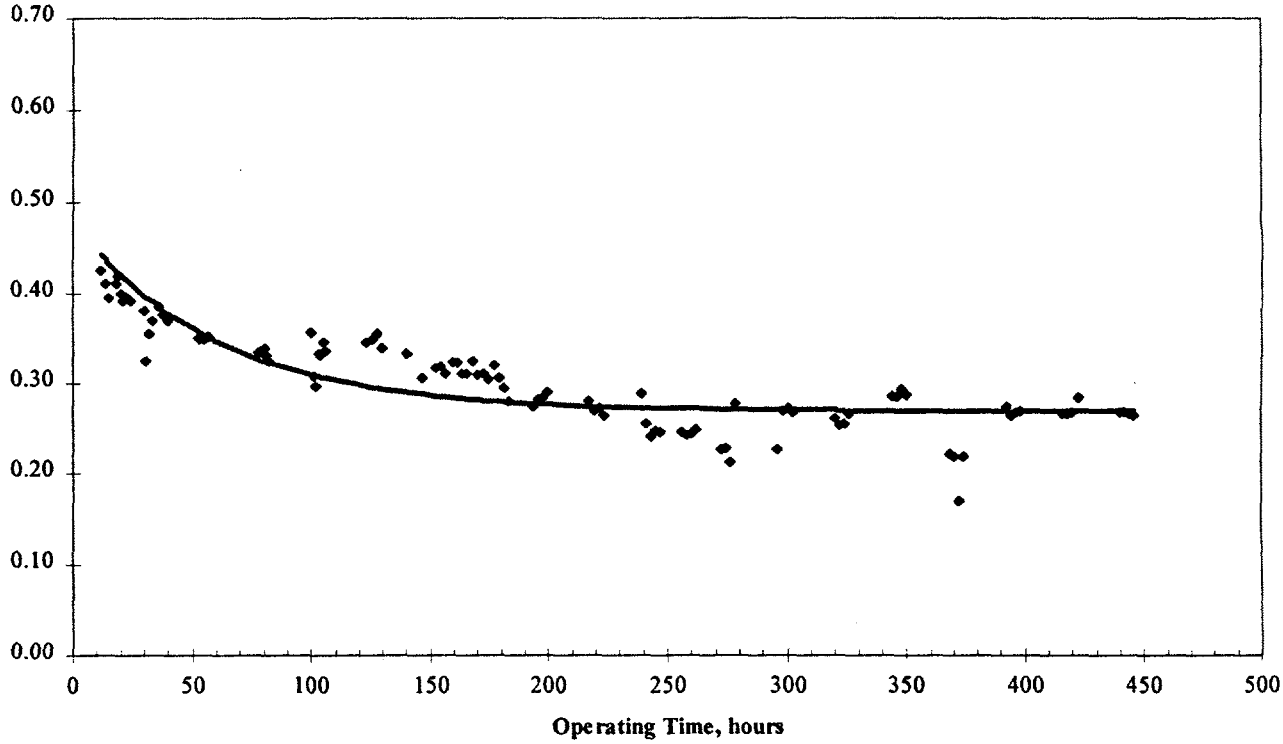

Figure 5 - Filter Permeance vs. Operating Time

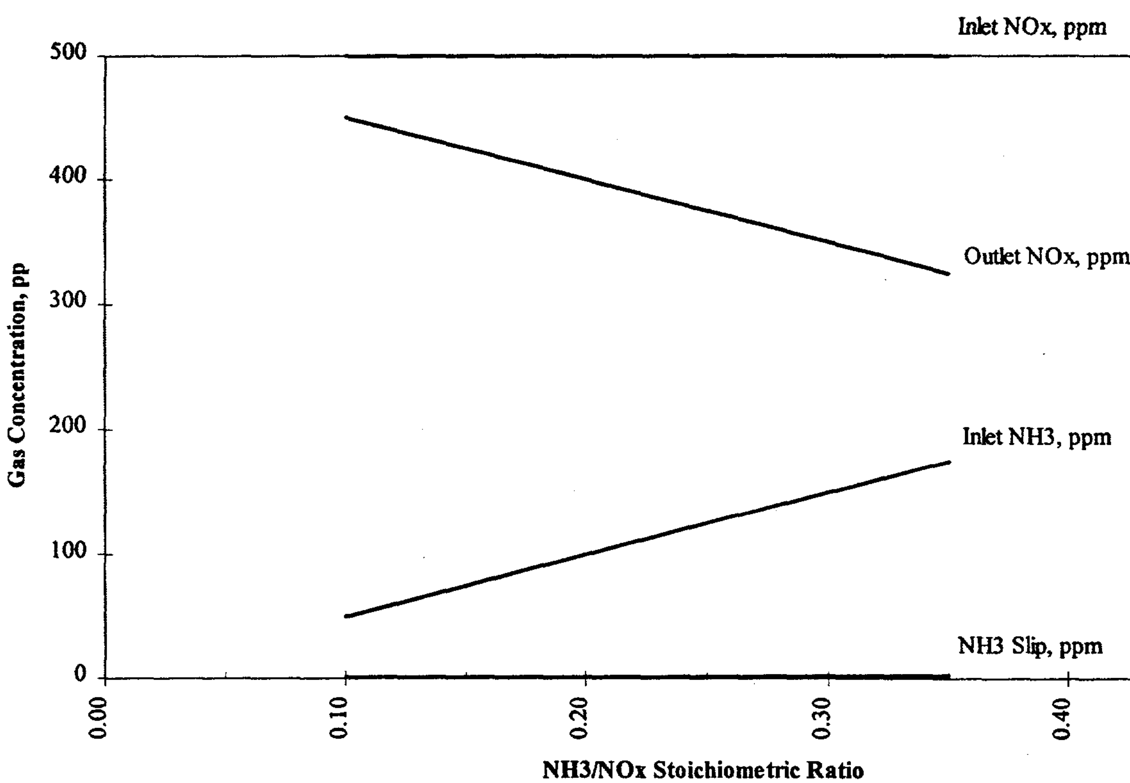

Figure 6 - NOx Reduction

Future Tests. It is unlikely that an advancement in catalyst deposition technology will be made that will achieve an initial tubesheet pressure differential of less than 8 inches w.g. within the 100 ACFM Test time frame. A second 500-hour test will be conducted to gather engineering data on the performance of a non-catalytic filter system. Catalyst development is continuing in a parallel program, with the hope of being able to achieve project goals by completion of Phase II.

POCTF DESIGN AND LICENSING WITH A KALINA CYCLE

Introduction. The centerpiece of the LEBS project is Phase IV which will undertake the design, construction and test operation of a proof-of-concept test facility (POCTF). These final-phase activities will provide the design and operating database critical to commercialization of the LEBS technologies. At present, the team is developing a site-specific preliminary design for their POCTF, and has project licensing in progress.

Project Description. The team was fortunate in obtaining a commitment for an outstanding host site for the POCTF. Richmond (Indiana) Power & Light Co. (RP&L) has offered to host the project at their Whitewater Valley station. RP&L has a history of successful involvement in technology demonstration programs, including one of the earliest low NO_X burner installations, a LIMB installation, and a Clean Coal Technology project.

The Whitewater Valley plant is composed of two coal-fired, non-reheat units, with nominal ratings of 33 MWe (Unit 1) and 66 MWe (Unit 2). Unit 1 will be modified to accept the LEBS technology package. This unit is approximately 40 years old, and incorporates a 900F/900 psig steam cycle with a steam capacity of 325,000 lb/hr. The POCTF project will involve a major restructuring of the unit, that entails the replacement of the complete power system (boiler, turbine-generator, feedwater heaters, power piping) with a new Kalina-based power system, and addition of the LEBS flue gas cleanup system. The project will use the plant infrastructure to the maximum extent practical, including coal handling, heat rejection, ash handling, powerhouse structures, and auxiliary systems. Although the project is being implemented as a test facility, RP&L intends to use the unit for long-term production service following completion of the LEBS project. This criterion, therefore, has a dominant effect on specification and design of the equipment and the facility. The approach taken in establishing the size of the modified unit has been to maximize its generating capacity, consistent with making maximum use of existing plant infrastructure. Key plant performance parameters are summarized in Table 2.

By leveraging the significant improvement in heat rate offered by the Kalina cycle with a modest 10% increase in coal heat input, the unit output will be increased a substantial 43% to about 48 MWe, with a corresponding 23% decrease in heat rate. At the projected net unit heat rate of about 9,200 Btu/kWh, the modified Whitewater Valley Unit 1 will be the most efficient coal-fired unit of its size in the U.S. The planned project, in fact, compares favorably to the best coal-fired unit heat rate reported in the USA in 1994 of 8,889 Btu/kWh (annual average) for a 660 MW supercritical unit.

Equipment. Because the Kalina cycle optimizes at different thermodynamic conditions than a steam cycle, and because of the change in working fluid and the increase in generating capacity, the complete steam side of the power cycle is to be removed and replaced. Equipment to be replaced includes the boiler and auxiliaries, turbine-generator and auxiliaries, condenser, condensate system and feedwater system. The size of the unit has been selected such that the new vapor generator will fit in the existing boiler support-steel cavity, and the new turbine-generator will fit the existing turbine pedestal (after pedestal modification). The fact that the Kalina cycle regenerates substantially more heat than a steam cycle results in a significant increase in the number of regenerative heaters, such that a turbine hall addition will be required to house this new equipment.

The vapor generator, or boiler, design for the POCTF is a single reheat, drum type with pumped circulation for cooling furnace wall evaporative tubes. The Kalina cycle, with its higher rate of heat regeneration, requires less evaporation but more superheater and reheater duty in the vapor generator. Thus, in addition to pendant and horizontal superheater and reheater surfaces, in the preliminary design portions of the upper furnace walls are used for superheating and reheating the working fluid. The design of these sections is the same as conventional radiant wall reheater designs. The vapor generator looks very much like a large utility unit designed for a Rankine cycle.

Turbine design and performance for a Rankine or Kalina cycle are very similar. Ammonia has a molecular weight very close to that of pure water, (17 vs. 18). This allows the use of current designs for turbine blading and turbine shell to be used in a Kalina cycle. One major difference in the turbine, when used in a Kalina cycle, is that the turbine is changed to a back pressure configuration. In doing so, there is no need for the large low pressure section and vacuum system which are required in the Rankine cycle. This provides a capital cost saving as well as improved system efficiency.

TABLE 2 - UNIT 1 PERFORMANCE PARAMETERS
(Preliminary)

		Existing	POCTF	Change
Coal Heat Input	MM Btu/hr	400	440	+ 10%
Cooling Tower Load	MM Btu/hr	216	215	
Generator Output	MWe	35.6	54.6	
Auxiliary Load	MWe	2.2	6.7	
Net Unit Generation	MWe	33.4	47.9	+ 43%
Net Unit Heat Rate	Btu/kWh	12,000	9,186	- 23%

In addition, the inclusion of the LEBS flue gas emissions control features dictates removal of the gas side power cycle systems. The replacement systems will include the low NO_x firing technology described previously, a new draft system, and a flue gas cleanup system. At present, two alternative processes are being evaluated for flue gas cleanup: the SNO_x™ hot process and an advanced dry-scrubbing process.

Control requirements associated with the Kalina power cycle, and the fact that Unit 1 still has its original control system, dictate that the project will include installation of a new unit-wide distributed control system. The increase in auxiliary power consumption associated with the modified unit also requires that the station service transformers for Unit 1 (unit auxiliary and startup) be replaced with larger capacity units, and substantial new power distribution capability be added.

Licensing. A licensing plan and schedule have been developed for the project that has identified the need to obtain twelve individual environmental/safety permits and approvals. The project will result in large reductions of all the regulated air emissions from Unit 1. Thus, approvals for the air permits are expected to be relatively straight forward. Unique to this power project, however, is the significant ammonia inventory required for operation of the Kalina cycle. The presence of this material on site will require the development of plans to deal with a potential accidental ammonia release.

CONCLUSIONS AND FUTURE WORK

Testing of the low-NO_x firing system has been completed. The work remaining is analysis of data from the second week of testing in the BSF. The NO_x emission target of 0.1 lb/MM Btu with <5% carbon in the fly ash was achieved in the BSF (actually 0.11 lb). However, at this time it cannot be predicted with certainty that 0.1 lb/MM Btu will be achieved in commercial size systems. There presently is no further LEBS firing system development work planned prior to construction of the POCTF.

The preliminary results of the catalytic filter field testing were very encouraging regarding particulate emissions and NO_x reduction. However, measured gas draft loss was excessive. Since approximately 75% of the draft loss is attributed to the catalyst, testing will continue with a non-catalytic filter system while catalyst deposition technology is reviewed. Also, since it is possible that the catalytic filter draft loss situation may not be resolved within the POCTF schedule, an alternative technology will be evaluated.

The POCTF preliminary design work will be completed within the project schedule. A full release for detailed engineering, manufacturing, *etc.* is expected in mid to late 1997.

REFERENCES

1. J. W. Regan., et al, "ABB's LEBS Activities - A Status Report", First Joint Power & Fuel Systems Contractors Conference, Pittsburgh, PA, 1996

APPENDIX D - 17 pages

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